Draft Permit

STATE OF MISSOURI

DEPARTMENT OF NATURAL RESOURCES

MISSOURI AIR CONSERVATION COMMISSION

PERMIT TO CONSTRUCT

Under the authority of RSMo 643 and the Federal Clean Air Act the applicant is authorized to construct the air contaminant source(s) described below, in accordance with the laws, rules and conditions as set forth herein.

Permit Number:	Project Number: 2006-12-036
Parent Company:	City Utilities of Springfield
Parent Company Address:	301 East Central, PO Box 551, Springfield, MO 65801
Installation Name:	City Utilities of Springfield – James River Power Station
Installation Address:	5701 South Kissick Road, Springfield, MO 65801
Location Information:	Greene County, S20, T28N, R21W

Application for Authority to Construct was made for:
Replacement of existing Over-Fire Air (OFA) combustion controls and upgrade of existing burner configuration with an "ultra low-NO_X" design on Unit 3, Unit 4, and Unit 5 to reduce nitrogen oxide (NO_X) emissions from the affected units. A High Energy Reagent Technology (HERT) system will be installed for additional NO_x control throughout the units' operating load range. This review was conducted in accordance with Section (8), Missouri State Rule 10 CSR 10-6.060, *Construction Permits Required*.

☐ Standard Conditions (on reverse) are applicable to this permit.

☐ Standard Conditions (on reverse) and Special Conditions are applicable to this permit.

EFFECTIVE DATE	DIRECTOR OR DESIGNEE DEPARTMENT OF NATURAL ESOURCES

STANDARD CONDITIONS:

Permission to construct may be revoked if you fail to begin construction or modification within 18 months from the effective date of this permit. Permittee should notify the Air Pollution Control Program if construction or modification is not started within 18 months after the effective date of this permit, or if construction or modification is suspended for one year or more.

You will be in violation of 10 CSR 10-6.060 if you fail to adhere to the specifications and conditions listed in your application, this permit and the project review. In the event that there is a discrepancy between the permit application and this permit, the conditions of this permit shall take precedence. Specifically, all air contaminant control devises shall be operated and maintained as specified in the application, associated plans and specifications.

You must notify the department's Air Pollution Control Program of the anticipated date of start up of this (these) air contaminant sources(s). The information must be made available not more than 60 days but at least 30 days in advance of this date. Also, you must notify the Department of Natural Resources Regional office responsible for the area within which you are located with 15 days after the actual start up of this (these) air contaminant source(s).

A copy of this permit and permit review shall be kept at the installation address and shall be made available to Department of Natural Resources' personnel upon request.

You may appeal this permit or any of the listed special conditions to the Administrative Hearing Commission (AHC), P.O. Box 1557, Jefferson City, MO 65102, as provided in RSMo 643.075.6 and 621.250.3. If you choose to appeal, you must file a petition with the AHC within 30 days after the date this decision was mailed or the date it was delivered, whichever date was earlier. If any such petition is sent by registered mail or certified mail, it will be deemed filed on the date it is mailed. If it is sent by any method other than registered mail or certified mail, it will be deemed filed on the date it is received by the AHC.

If you choose not to appeal, this certificate, the project review and your application and associated correspondence constitutes your permit to construct. The permit allows you to construct <u>and</u> operate your air contaminant sources(s), but in no way relieves you of your obligation to comply with all applicable provisions of the Missouri Air Conservation Law, regulations of the Missouri Department of Natural Resources and other applicable federal, state and local laws and ordinances.

The Air Pollution Control Program invites your questions regarding this air pollution permit. Please contact the Construction Permit Unit at (573) 751-4817. If you prefer to write, please address your correspondence to the Missouri Department of Natural Resources, Air Pollution Control Program, P.O. Box 176, Jefferson City, MO 65102-0176, attention: Construction Permit Unit.

SPECIAL CONDITIONS:

The permittee is authorized to construct and operate subject to the following special conditions:

The special conditions listed in this permit were included based on the authority granted the Missouri Air Pollution Control Program by the Missouri Air Conservation Law (specifically 643.075) and by the Missouri Rules listed in Title 10, Division 10 of the Code of State Regulations (specifically 10 CSR 10-6.060). For specific details regarding conditions, see 10 CSR 10-6.060 paragraph (12)(A)10. "Conditions required by permitting authority."

City Utilities of Springfield – James River Power Station
Greene County, S20, T28N, R21W

1. Standards of Performance for Best Available Control Technology (BACT) for Carbon Monoxide (CO)
   A. James River Power Station shall not emit more than 0.35 pounds of CO per million British Thermal Units (lb/MMBTU) of heat input each from Unit 3, Unit 4,and Unit 5 based on a 30-day rolling average. This limit is exclusive of emissions occurring during start-up, shutdown and malfunction.

   B. James River Power Station shall not emit more than 3,213 tons per year of CO combined from Unit 3, Unit 4, and Unit 5. This limit is inclusive of emissions during start-up, shutdown and malfunction.

   C. James River Power Station shall operate continuous CO emission monitors to measure, record and report CO emissions compliance with the Conditions 1A and 1B listed above.

2. Continuous Emission Monitoring System (CEMS) – Unit 3, Unit 4, and Unit 5
   A. James River Power Station shall install, certify, operate, calibrate, test and maintain CEMS for CO and any necessary auxiliary monitoring equipment in accordance with all applicable regulations. If there are conflicting regulatory requirements, the more stringent shall apply.

   B. CEMS certification shall be made pursuant to 40 CFR Part 60, Appendix B, Performance Specification 4.

   C. Periodic quality assurance assessments shall be conducted according to the procedures outlined in 40 CFR Part 60, Appendix F.

   D. James River Power Station shall install and operate a data acquisition and handling system to calculate emissions in terms of the emission limitations specified in this permit.

3. Record Retention Requirements
   James River Power Station shall maintain all records required by this permit, on-site,

SPECIAL CONDITIONS:

The permittee is authorized to construct and operate subject to the following special conditions:

for the most recent 60 months of operation and shall make such records available immediately to any Missouri Department of Natural Resources’ personnel upon request.

4. Reporting Requirements
James River Power Station shall report CO emissions in their semi-annual monitoring (SAM) report and in the annual compliance certification (ACC) statement.

Draft Permit

REVIEW OF APPLICATION FOR AUTHORITY TO CONSTRUCT
SECTION (8) REVIEW
Project Number: 2006-12-036
Installation ID Number: 077-0005
Permit Number:

James River Power Station
5701 South Kissick Road
Springfield, MO 65804

Complete: December 13, 2006

Parent Company:
City Utilities of Springfield
P.O. Box 551
Springfield, MO 65801-0551

Greene County, S20, T28N, R21W

REVIEW SUMMARY

- James River Power Station has applied for authority to replace the existing Over-Fire Air (OFA) combustion controls and upgrade its existing burner configuration with an "ultra low-NO_X" design on Unit 3, Unit 4, and Unit 5 to reduce nitrogen oxide (NO_X) emissions from the affected units. A High-Energy Reagent Technology (HERT) system will be installed for additional NO_X control throughout the units' operating load range. Urea is used as the reagent to control NO_X. Further, urea injection has been proven to help increase ash resistivity and enhance particulate collection by electrostatic precipitators.

- Hazardous Air Pollutant (HAP) emissions are not expected from the proposed equipment.

- None of the New Source Performance Standards (NSPS) apply to the proposed equipment.

- None of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) or currently promulgated Maximum Achievable Control Technology (MACT) regulations applies to the proposed equipment.

- The Best Available Control Technology (BACT) requirements apply to the proposed equipment. Good combustion practices will control carbon monoxide (CO) emissions to a level of 0.35 lb/MMBTU on a 30-day rolling average.

- This review was conducted in accordance with Section (8) of Missouri State Rule 10 CSR 10-6.060, *Construction Permits Required*. Potential emissions of CO are above the major source threshold of 100 tons per year.

- This installation is located in Greene County, an attainment area for all criteria air pollutants.

- This installation is on the List of Named Installation [10 CSR 10-6.020(3)(B), Table 2, Number 26 – *Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input*]. Therefore, the major source threshold for all criteria pollutants is 100 tons per year.

- Ambient air quality modeling was performed to determine the ambient impact of CO.

- Emissions testing is not required for the source.

- Revision to the Part 70 Operating Permit application is required for this installation within 1 year of equipment startup.

- Approval of this permit is recommended with special conditions.

INSTALLATION DESCRIPTION

James River Power Station (JRPS) is a fossil-fuel steam electric generation facility owned and operated by City Utilities of Springfield, Missouri. JRPS consists of five coal-fired electric utility steam generating units (EUSGUs) with a gross electrical output capacity of 253-megawatt (MW) and two combustion turbines with a combined output 147 MW. The five pulverized coal-fire units have an aggregate maximum design heat input rate of 2,596 MMBTU/hr. Power River Basin (PRB) coal is burned in these units. Particulate matter emissions are controlled using electrostatic precipitators.

The installation is a major source for both construction and operating permits. JRPS is considered a Part 70 source and an operating permit, Permit No. OP2001-049 was issued in June 2001. The Part 70 permit renewal application (project no. 2005-12-024) was received on December 14, 2005 and is currently under technical review.

The following construction permits have been issued to JRPS from the Air Pollution Control Program.

Table 1. Previously Issued Construction Permits

Permit Number	Description
1085-002A	Dry Fly Ash Collection System
0888-002A	Construct Gas Turbine
0391-002 (PSD)	Installation Of Second Gas Turbine Generator
0697-008	Construction Of Coal Unloading And Handling Equipment
042000-016	Installation Of Water Fogging System To Air Inlet Of CT#12
082001-003	Modification To Increase Coal Handling And Unloading
032003-017	Modification Of Fly Ash Collection System
032003-017A	Amendment To Permit No. 032003-017
102006-006	Propane Peak Shaving

PROJECT DESCRIPTION

James River Power Station is proposing to replace its Over-Fire Air (OFA) combustion control system on three of its pulverized coal-fired units (i.e., Unit 3, 4 and 5) It also proposes to upgrade existing burner configuration to an “ultra low-NO_X” design. These modifications will significantly reduce annual and seasonal NO_X emissions.

NO_X reduction is achieved by limiting the amount of free oxygen (O_2) that can combine with nitrogen. An over-fire air system takes a portion of the O_2 usually injected into the combustion zone and adds it higher up in the furnace. Removing a percentage of O_2 supplied to the combustion zone results in an incomplete combustion and lower combustion gas temperatures providing insufficient conditions to support NOx formation. The O_2 removed from the combustion zone is then added higher up in the furnace to complete combustion with minimal NOx production. NO_X emissions are expected to decrease by at least 57% (a reduction of around 0.20 lb/MMBTU), or by almost 3,000 tons per year.

Collateral CO emissions are expected when OFA combustion controls are utilized. This generation takes place primarily in the lower furnace. Further combustion takes place while combustion air resides in the boiler, thereby reducing CO concentrations in the upper furnace.

In determining Prevention of Significant Deterioration (PSD) applicability, a comparison of future potential emissions for regulated pollutants was made with past actual emissions. The resultant difference exceeded the major source threshold for CO of 100 tons per year, making the project subject to PSD review. Baseline actual emissions for EUSGUs are calculated as the average emissions during any two-year period within the five-year period preceding a modification. For this analysis 2004 and 2005 actual emissions were used. These emissions were calculated using Environmental Protection Agency’s Factor Information Retrieval (FIRE) Data System/AP-42 emission factor of 0.5 lb CO/ton coal burned. Since there has been no site-specific CO testing conducted, actual emissions could vary from this value.

Electric utilities are allowed to use a less conservative past actual to future actual calculation methodology, but the applicant would then be required to track post-project emissions for a period of 5 years following the project. However, JRPS has decided to pursue the more conservative option of utilizing the past actual to future potential methodology, causing them to undergo PSD review.

Past OFA projects like this were considered pollution control projects (PCP) as defined in 40 CFR Part 52.21 (b)(32)(iii) and were exempt from PSD permitting. PCP means any activity, set of work practices or project (including pollution prevention) undertaken at an existing emissions unit that reduces emissions of air pollutants from such unit. PCPs which result in an increase in non-targeted pollutants should be reviewed to determine that the collateral increase has been minimized and will not cause a violation of the applicable National Ambient Air Quality Standard. The PCP exemption was based on determination that the environmental benefit from an emission reduction outweighs the environmental detriment of any emission increase. However, on June 24, 2005, the U.S. Court of Appeals vacated the PCP provisions of the NSR rule. That means that as of June 24, 2005, the PCP provisions no longer exist and any pollution control device that results in collateral emissions increase of a regulated pollutant must be permitted dependent on the magnitude of those collateral emissions.

EMISSIONS/CONTROLS EVALUATOIN

Collateral emissions of CO resulting from operation of the OFA combustion controls are the pollutant of concern. Potential emissions were determined based on an emission factor of 0.35 lb/MMBTU of CO from each of the affected boilers operating at 100% load. The 0.35 lb/MMBTU is back calculated from an expected worst case CO concentration of 425 ppm for maximum NO_X control conditions as provided by the applicant. The equation and parameters in Table 2 were used in the back calculation. Total heat input for the boilers is 2096 MMBTU/hr with individual contributions assumed to be 496 MMBTU/hr, 600 MMBTU/hr and 1000 MMBTU/hr, respectively for Boiler 3, Boiler 4 and Boiler 5.

Table 2. Emission Factor - Equation and Parameters.

	Boiler #3	Boiler #4	Boiler #5
CO Concentration (ppmv) - c_s	425	425	425
O_2 in air (%)	20.9	20.9	20.9
Excess O_2 (%)	3	3	3
F_d (dscf/MMBTU)*	9780	9780	9780
CO (lb/scf)	0.0729	0.0729	0.0729
Heat Input (MMBTU/hr)	496	600	1000
E, Emission Factor, (lb/MMBTU) $E = c_s F_d \times \left(\frac{20.9}{20.9 - \%O_2} \right)$	0.35	0.35	0.35

* F_d is the dry F factor as classified according to ASTM D388-77

Potential emissions of the application represent the potential of the new equipment, assuming continuous operation (8760 hours per year) at the maximum hourly design heat input. Existing actual emissions were calculated as the average emissions during 2004 and 2005 and were taken from the applicant's 2004 and 2005 Emissions Inventory Questionnaire (EIQ) submittal. Existing potential emissions, except CO, were taken from Permit No. 102006-006. Existing CO emissions were recalculated using emission factors obtained from the Environmental Protection Agency (EPA) document AP-42, *Compilation of Air Pollutant Emission Factors*, Fifth Edition, Section 1.1 *Bituminous And Subbituminous Coal Combustion (9/98)*, Section 1.4 *Natural Gas Combustion (7/98*), Section 1.5 *Liquefied Petroleum Gas Combustion (10/96),* on limits from Permit No. 0391-002 and on maximum hourly design rates (MHDR) included in the permit application. Table 3 provides an emissions summary for this project.

Table 3. Annual Emissions Summary and PSD Significance Levels (tons per year).

Pollutants	PSD Significance Level	Existing Potential Emissions	Existing Actual Emissions (2005 EIQ)	Existing Actual Emissions (2004 EIQ)	Emissions Increases/ Reductions for this application
PM_{10}	15	1065	254	315	N/A
SO_2	40	32157	4894	4925	N/A
NO_X	40	9078	4013	3675	Decrease
VOC	40	147	33	32	N/A
CO	100	445	276	264	2943
HAPs	10/25	796	40	86	N/A
Lead	0.6	0.0	0.0	0.0	N/A

*N/A = Not Applicable

PERMIT RULE APPLICABILITY

This review was conducted in accordance with Section (8) of Missouri State Rule 10 CSR 10-6.060, *Construction Permit Required*. Potential emissions of CO are above the major source threshold.

APPLICABLE REQUIREMENTS

JRPS shall comply with the following applicable requirements. The Missouri Air Conservation Laws and Regulations should be consulted for specific record keeping, monitoring, and reporting requirements. Compliance with these emission standards, based on information submitted in the application, has been verified at the time of this application was approved. For a complete list of applicable requirements for your installation, please consult your operating permit.

GENERAL REQUIREMENTS

- *Submission of Emission Data, Emission Fees and Process Information*, 10 CSR 10-6.110
  The emission fee is the amount established by the Missouri Air Conservation Commission annually under Missouri Air Law 643.079(1). Submission of an Emissions Inventory Questionnaire (EIQ) is required June 1 for the previous year’s emissions.

- *Operating Permits*, 10 CSR 10-6.065

- *Restriction of Particulate Matter to the Ambient Air Beyond the Premises of Origin*, 10 CSR 10-6.170

- *Restriction of Emission of Visible Air Contaminants*, 10 CSR 10-6.220

- *Restriction of Emission of Odors*, 10 CSR 10-4.070

- *Open Burning Restrictions*, 10 CSR 10-4.090

SPECIFIC REQUIREMENTS

- *Maximum Allowable Emissions of Particulate Matter From Fuel Burning Equipment Used for Indirect Heating*, 10 CSR 10-4.040

- *Restriction of Emission of Sulfur Compounds*, 10 CSR 10-6.260

- *Emission Limitations and Emissions Trading of Oxides of Nitrogen*, 10 CSR 10-6.350.

BACT ANALYSIS

Introduction

Any source subject to Missouri State Rule 10 CSR 10-6.060, Construction Permits Required, Section (8) must conduct a BACT analysis on any pollutant emitted in amounts greater than de minimis levels. The BACT requirement is detailed in Section 165(a)(4) of the Clean Air Act, at 40 CFR 52.21 and 10 CSR 10-6.060(8)(B).

A BACT analysis is done on a case-by-case basis and is performed in general by using a “top-down” method. The 1990 Workshop Manual identifies the basic steps of a “top-down” BACT analysis as follows:

1. Identification of all control technologies.
2. Elimination of technically infeasible options.
3. Ranking of the remaining control technologies by control effectiveness.
4. Determination of the most cost-effective control technology.
5. Selection of BACT.

Potential CO Control Technologies

CO emissions can be controlled by either minimizing CO formation during combustion or by post-combustion oxidation systems to oxidize any CO formed in the combustion process.

1. Combustion Controls
    - Good Combustion Practices
2. Post-Combustion Controls
    - Conventional Oxidation Catalyst
    - Add-on Afterburner Controls

Good Combustion Practices.

Good combustion practices prevent formation of CO during combustion. A number of measures can be taken to ensure that CO generation is minimized, including: maintaining proper fuel-to-air-flow ratios; visually monitoring combustion conditions for excessive haze, ash agglomeration and bridging on boiler tubes; periodically checking coal mill performance for coal fineness; periodically measuring unburned carbon to determine how combustion can be optimized; determining proper control settings for optimum efficiency and minimal CO generation; and empirically determining optimal CO emission rates and NO_x emission reduction during unit testing and tuning.

Conventional Oxidation Catalyst

Catalytic oxidation requires oxygen, minimal heat and a catalyst to convert CO to CO_2. Catalytic oxidation is widely used in the refinery industry and for gas turbines in the utility industry.

The noble metal catalysts typically used in catalytic oxidation are highly susceptible to poisoning from sulfur compounds resulting from coal combustion. The high particulate loading found in most coal-fired flue gas streams would cause rapid deactivation and fouling of the catalyst. Placement of the oxidation unit downstream from the particulate matter control device would make re-heating of the exhaust stream necessary, increasing emissions of NO_X and PM_{10} from combustion of additional fuel. The conditions necessary for CO conversion also favor the conversion of SO_2 to SO_3. The SO_3 would combine with moisture in the flue gas, increasing sulfuric acid mist emissions from the stack. Catalytic oxidation is not employed on coal-fired boilers due to the reasons cited above rendering it technically infeasible for application at JRPS.

Add-on Afterburner Controls (Thermal Oxidation).

Thermal oxidation also uses heat and oxygen for the CO to CO_2 conversion, but without the use of a catalyst. Temperatures in excess of 1,500^{o}F are required. As with the catalytic oxidation units, the thermal oxidizer (afterburner) would need to be located downstream of the particulate matter control device, to prevent fouling. Heat exchangers and a natural gas furnace would be needed to raise the temperature from approximately 350^{o}F to the required temperature. Additional NO_x and PM_{10} emissions would result. The same problems exist for thermal oxidation as for catalytic oxidation.

There are no post-combustion controls in use on coal-fired boilers at this time. The use of thermal oxidation has historically been for the control of volatile organic compounds. Thermal oxidation is not considered to be technically feasible in this case.

BACT for CO

Good combustion control practices are the only technically feasible alternative for minimizing CO emissions. CO emissions following the OFA/LNO_X project are expected to be near 200 ppm at full unit load but could range from 200-500 ppm over the entire operating range of the units. Potential CO emissions are not expected to exceed a concentration of 425 ppm (at 3% excess O_2).

A level of 0.35 lb/MMBTU heat input is chosen as the BACT limit (exclusive of start-up, shutdown and malfunction) on a 30-day rolling average. According to the RACT/BACT/LAER Clearinghouse (RBLC) utility boilers retrofitted with OFA combustion controls have been given CO BACT limits ranging from 0.23 lb/MMBTU to 1.26 lb/MMBTU.

James River Power Station shall utilize CEMS to monitor the CO emissions from the affected units. In addition to the lb/MMBTU emissions limit, an annual CO emission limit of 3,213 tons on a 12-month rolling basis will include start-up, shutdown and malfunction events.

AMBIENT AIR QUALITY IMPACT ANALYSIS

An Ambient Air Quality Impact Analysis (AAQIA) must be completed for any air contaminant that exceeds the de minimis emission levels outlined in 10 CSR 10-6.020(3)(A) Table 1. The AAQIA determines the ambient impact of emissions at or beyond the property boundary of the installation. James River Power Station conducted air dispersion modeling using the latest version of the SCREEN 3 model (Version 96043) for each unit and combined the maximum concentrations ($\mu g/m^3$) to determine impacts. The combined preliminary modeling results for both the 1-hour and 8-hour standards were below the significance level. Additional impacts on visibility, growth, soils, plants and animals were also evaluated within the Class II area surrounding the facility.

PSD Increment is the maximum allowable increase in ambient concentrations of specific pollutants from all sources in a baseline area after the minor source baseline date. Only those pollutants and the associated averaging times that exceed the PSD significance level are reviewed for increment consumption. There is not increment level for CO and therefore, CO was not evaluated for increment consumption.

The screening analysis was conducted to determine if James River Power Station would be required to perform preconstruction monitoring, additional air quality modeling, or if the installation could forego further analysis altogether. If the preliminary analysis indicates that the facility will not significantly impact the air quality within a region, no further analysis is required. In addition to providing an indication of whether CO must undergo a full impact analysis, the results of the preliminary analysis determine what, if any, preconstruction monitoring will be required. If the preliminary analysis indicates that the facility will not exceed the monitoring significance level, no preconstruction monitoring is necessary.

The maximum emission rate expected across the operating load range for each unit of 0.35 lb/MMBTU was utilized in the analysis. Table 4 summarizes the results of the preliminary analysis. No further modeling or preconstruction monitoring is required for CO based on the results of the preliminary analysis.

Table 4. Significance Levels for Modeling and Preconstruction Monitoring ($\mu mg/m^3$).

Pollutant	Averaging Period	Modeling Significance Level	Preliminary Modeling Results[1]	Additional Modeling?	Pre-constructio n Monitoring Required?
CO	8-hour	500	301.05	No	No
	1-hour	2000	430.07		

[1]Off-site impacts based on combined maximum 1-hour concentrations from each unit. Separate model runs performed for Units 1-5. The conversion factor used to determine the 8-hour averaging period concentration from the 1-hour results is 0.7.

Air Quality Related Values (AQRV)

The additional air quality related impacts analysis requirements under PSD assess the ambient air quality impact analysis, soils and vegetation impacts, visibility impairment, and growth analysis for the project.

1. Construction Impacts

Construction related impacts from this project are expected to be minimal. Minimal to no short-term adverse air quality impacts to the surrounding area near JRPS are anticipated. Increased traffic in the area will be limited in time and scope based on delivery of system components and control technology consultant engineers. Higher traffic patterns can impact local air quality during certain meteorological conditions. However, these conditions are not likely to occur. Currently, fugitive dust is minimized by applying water on portions of the paved and unpaved haul roads. This practice will continue to be utilized to control dust during dry periods.

2. Vegetation Impacts

Based on the analysis for Southwest Unit 2, carbon monoxide is not known to injure plants nor has it been shown to be taken up by plants. Consequently, it is assumed that no adverse impacts to vegetation at or near the James River Power Station are expected for stack CO emissions from this project.

3. Soil Impacts

Low ambient concentrations of CO should not significantly affect soil concentrations in the immediate vicinity.

4. Impacts on Threatened and Endangered Species

According to the Fish and Wildlife Service (FWS), the only federally protected species known to occur in the project area are the threatened Ozark cavefish (*Amblyopsis rosae*) and endangered Gray bat (*Myotis grisescens*). These sensitive species were thoroughly reviewed in the Additional Impacts Analysis provided by Burns & McDonnell for Southwest Unit 2. Impacts to threatened and endangered species due to this project are not expected during construction. The proposed modifications will have no operational impacts to protected wildlife or habitats in the vicinity of the power station.

5. Growth Impacts

The modification of the existing OFA/LNOx burners is not expected to increase employment in the area. The building phase of the project is expected to temporarily increase the installation's workforce due to construction labor. The proposed modification will not contribute to a significant increase in the local population.

6. Class I and II Area Visual Impact Analysis

The nearest Class I area to the James River Power Station is Hercules Glade Wilderness Area in southern Missouri. This Class I area is approximately 55 km from the James Power Station. The SCREEN3 model was performed which indicated results below the modeling significance impact levels for CO for both the 1-hr and 8-hr averaging periods. Visibility is a function of particulate and NO_x emissions. The reduction of NO_x from this project will serve to improve the visibility impacts from the major source. There is no increment level for CO, therefore no further air quality or Class I or Class II visibility analysis was performed.

STAFF RECOMMENDATION

On the basis of this review conducted in accordance with Section (8), Missouri State Rule 10 CSR 10-6.060, *Construction Permits Required*, I recommend this permit be granted with special conditions.

Maurice Chemweno	Date
Environmental Engineer	

PERMIT DOCUMENTS

The following documents are incorporated by reference into this permit:

- The Application for Authority to Construct form, dated December 11, 2006, received December 13, 2006, designating City Utilities of Springfield as the owner and operator of the installation.
- U.S. EPA document AP-42, *Compilation of Air Pollutant Emission Factors*, Fifth Edition.
- 40 CFR Part 60, Appendix A-7, Section 17, Table 19-2 and Equation 19-1.
- Regional Office Site Survey, dated December 28, 2006.